

## Accepted Manuscript

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PII: S0264-8172(12)00085-2

DOI: 10.1016/j.marpetgeo.2012.04.001

Reference: JMPG 1575

To appear in: *Marine and Petroleum Geology*

Received Date: 14 February 2012

Revised Date: 5 April 2012

Accepted Date: 7 April 2012

Please cite this article as: Davies, R.J., Mathias, S., Moss, J., Hustoft, S., Newport, L., Hydraulic fractures: How far can they Go?, *Marine and Petroleum Geology* (2012), doi: 10.1016/j.marpetgeo.2012.04.001

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**Hydraulic Fractures: How Far Can They Go?**

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**ABSTRACT**

The maximum reported height of an upward propagating hydraulic fracture from several thousand fracturing operations in the Marcellus, Barnett, Woodford, Eagleford and Niobrara shale (USA) is ~ 588 m. Of the 1170 natural hydraulic fracture pipes imaged with three-dimensional seismic data offshore of West Africa and mid-Norway it is ~ 1106 m. Based on these empirical data, the probability of a stimulated and natural hydraulic fracture extending vertically > 350 m is ~ 1% and ~ 33% respectively. Constraining the probability of stimulating unusually tall hydraulic fractures in sedimentary rocks is extremely important as an evidence base for decisions on the safe vertical separation between the depth of stimulation and rock strata not intended for penetration.

## INTRODUCTION

Hydraulic fractures propagate when fluid pressure exceeds the least principal stress and the tensile strength of the host sediment (Hubbert & Willis 1957). They continue to propagate until the stress-intensity at the fracture tip is lower than the critical stress-intensity of the rock being fractured (e.g. Savalli, & Engelder 2005). These conditions can occur naturally (e.g. Cosgrove 1995) but they can also be stimulated to recover oil and gas (Simonson *et al.* 1978), or during injection of water into geothermal boreholes (e.g. Legarth *et al.* 2005; Julian *et al.* 2010) and unintentionally as the result of subsurface blowouts (e.g. Tingay *et al.* 2005).

Hydraulic fractures are commonly described in outcrops at centimetre to metre scale (e.g. Cosgrove 1995 - Fig. 1ab). They can be up to ~ 50 m in height in the Devonian Marcellus shale (e.g. Engelder & Lash 2008) and sand filled fractures (injectites) have been documented to extend hundreds of metres (Hurst *et al.* 2011). But three-dimensional (3D) seismic data now show that natural hydraulic fractures probably cluster, forming pipe-like features that often extend vertically for even greater distances than this (see Løseth *et al.* 2001; Zuhlsdorff & Spieß 2004; Cartwright *et al.* 2007; Davies & Clarke 2010).

Stimulation of hydraulic fractures as a technique for improved hydrocarbon production from low permeability reservoirs dates back to the late 1940s (Montgomery & Smith 2010). Measurements of the microseismicity they cause (e.g. Maxwell *et al.* 2002) have shown that they can extend for several hundred metres upwards and downwards from the wellbore (Fisher & Warpinski 2011). Multiple stages of hydraulic fracture stimulation on multiple wells are routine for the recovery of oil and gas from low permeability sedimentary reservoirs in shale gas provinces in the USA (e.g. King 2010). Shale gas exploration is starting in many other countries with sediments from Neogene to Cambrian age being potential future targets. Therefore constraining the probability of stimulating unusually tall hydraulic fractures in sedimentary rocks is critically important, as it will help avoid the unintentional penetration of shallower rock strata (Fig. 2) that might be important aquifers or subsurface geological storage sites.

Mathematical methods for estimating hydraulic fracturing height are simplistic (Fisher & Warpinski 2011) and it is generally accepted that we cannot yet accurately predict fracture

propagation behaviour in detail, so to date much of what we know of how fractures will behave *in situ* conditions comes from operational experience (King *et al.* 2008). Future shale gas targets could be in a variety of different stress regimes and in rocks with varied mechanical properties and ages. Therefore at this stage our approach is to include a wide range of the tallest examples of hydraulic fractures that have different geometries, geological settings and trigger mechanisms.

Although hydraulic fractures are 3D, here we compile new and existing data on the extents of only the vertical component of both natural and stimulated hydraulic fracture systems hosted in sediment from Neogene to Devonian in age from eight different locations (Fig. 3a). We briefly report on key statistics, compare them and consider which factors control the extent of upward fracture propagation.

### Hydraulic fracturing

There are several types of natural hydraulic fracture: injectites (e.g. Hurst *et al.* 2011), igneous dikes (e.g. Polteau *et al.* 2008), veins (e.g. Cosgrove, 1995), coal cleats (e.g. Laubach *et al.* 1998), and joints (e.g. McConaughy & Engelder, 1999). They have been extensively studied. In the case of joints in the Devonian Marcellus Formation, USA, it is even possible to study how they grow on the basis of plume lines that occur at centimetre to metre scale (Savalli, & Engelder, 2005). Marcellus shale fractures are thought to form due to gas diffusion and expansion within shale through multiple propagation events. In contrast the tallest examples of hydraulic fractures tend to cluster, are commonly termed chimneys, pipes or blowout pipes (herein we use the term 'pipe') and can extend vertically for hundreds of metres (e.g. Cartwright *et al.* 2007; Huuse *et al.* 2010). The origin of pipes is not certain, but they probably form due to critical pressurisation of aquifers and oil and gas accumulations (Zuhlsdorff & Spieß 2004; Cartwright *et al.* 2007; Davies & Clarke 2010). Pipe development may be followed by stoping, fluid-driven erosion and collapse of surrounding strata (Cartwright *et al.* 2007). Gases that have come out of solution and expand during fluid advection may also contribute to their development (Brown, 1990; Cartwright *et al.* 2007). They are recognised on seismic reflection data on the basis of vertically aligned discontinuities in otherwise continuous reflections (Fig. 3b and Cartwright *et al.* 2007; Løseth *et al.* 2011).

Stimulated hydraulic fractures are created to significantly increase the rate of production of oil and gas from fine-grained, low permeability sedimentary rocks such as shale. Commonly a vertical well is deviated so that it is drilled strata-parallel through the shale reservoir (Fig. 2). The production casing is perforated and hydraulic fractures stimulated by injecting saline water with chemical additives. 'Proppant' (for example sand) is used to keep the fractures open (see King 2010). Hydraulic fracture stimulation from a horizontal borehole is usually carried out in multiple stages with known volumes and compositions of fluid (e.g. Bell & Brannon 2011). Rather than pipes forming, clustering of fractures commonly occurs along planes, which are theoretically orthogonal to the least principle stress direction. So there are fundamental differences in the geometry of these fracture systems compared to those that cluster to form pipes, the reasons for which are not yet understood.

Hydraulic fractures can also be stimulated unintentionally for example as an underground blowout (e.g. Tingay 2003) and they can unintentionally be caused by the injection of waste water at high enough rates to generate pore pressures which exceed the pressure required for hydraulic fracturing (e.g. Løseth *et al.* 2011).

## DATASETS

Hundreds of pipes have recently been identified on 3D seismic reflection surveys in continental margin settings (Davies and Clarke 2010; Hustoft *et al.* 2010; Moss & Cartwright 2010; Løseth *et al.* 2011). We compile new data based upon these surveys on the vertical extents of 1170 pipes (e.g. Fig. 3ab). Pipe heights were measured by recording their bases and tops in two-way-travel time and converting these to heights using estimated seismic velocities for the host successions (Davies & Clarke, 2010; Moss & Cartwright, 2010; Hustoft *et al.* 2010). Errors are related to the seismic resolution and the estimation of the velocity of the sediment and are probably  $< 20\%$ . Because of the limits of vertical seismic resolution the numbers of hydraulic fractures that have vertical extents of less than 100 m are probably underestimated. We have not included in this study the heights of vertically extensive injectites or igneous intrusions because their likely modes of formation are quite different to stimulated hydraulic fractures and pipe structures.

The vertical and horizontal extents of stimulated hydraulic fractures used to recover hydrocarbons can be estimated using the energy released by the hydraulic fracturing which is recorded as microseismicity in a nearby borehole (e.g. Maxwell *et al.* 2002). Both tension and shear fractures are detected. We used a compilation of microseismic events (Fisher & Warpinski, 2011). They presented measurements of the fracture tops and bottoms for ‘thousands’ of mapped fracture treatments performed in the Barnett, Woodford, Marcellus and Eagle Ford shale gas formations recorded from early 2001 to the end of 2010 (their figures 2-6 respectively). A fifth unpublished dataset from the Niobrara shale (Colorado, USA) was compiled in the same way and released by Halliburton for publication here. These operations varied in terms of the depth of fracturing operations, the execution of the fracturing process and the geological setting. It represents the majority of the data released into the public domain at the time of writing.

Because we did not have access to the primary database our measurements of fracture height were made by digitising their published and unpublished graphs (Fisher & Warpinski, 2011 - Fig. 3c). This will have introduced errors but again this will be mainly with the shorter hydraulic fractures (with vertical extents < 100 m) therefore the numbers of these are also underestimated. Because it is the taller fractures we focus on, this bias does not change our main conclusions. There are also errors associated with the microseismic method, mainly associated with estimating the velocity of the rock between the hydraulic fracture and the monitoring well (e.g. Maxwell *et al.* 2002).

There is significant uncertainty in the depth of the initiation of fracture systems caused by underground well blowouts, hence we do not draw on this source of data in this paper. But the depth of the fracture initiation is well constrained where waste water is being injected, so here we use a recently reported example from the Tordis Field, offshore Norway where the fractures eventually intersected the seabed (Løseth *et al.* 2011). This example provides some additional context for the natural and stimulated datasets described.

## RESULTS

### Natural hydraulic fractures

Offshore of Mauritania 368 vertical pipes were identified over an area of 1880 km<sup>2</sup> (Davies & Clarke 2010 - Fig. 3ab) and it was possible to measure the vertical extent of 360 of these. They are hosted on a passive continental margin, probably within fine-grained turbidites and foram-nannofossil hemipelagites of Neogene age (Henrich *et al.* 2010). A graph of frequency against vertical extent shows the most common vertical extent is between ~ 200 m and ~ 300 m. The tallest conduit is ~ 507 m (Fig. 4a). The average vertical extent is 247 m.

Offshore of Namibia, we measured 366 vertical chimneys in a succession composed of fine grained claystones of Miocene to Recent age (Moss & Cartwright 2010). The average vertical extent is 360 m. The maximum vertical extent is ~ 1106 m (Fig. 4a). Vertical chimneys also form offshore mid Norway within the Oligocene to Recent fine grained mudstone and siliceous mudstones of the Brygge, Kai and Naust Formations (Hustoft *et al.* 2010). 66% of these terminate at the seabed. Of the 446 pipes the average vertical extent is 338 m. The maximum vertical extent is ~ 882 m (Fig. 4a). Graphs of hydraulic fracture height against the probability of non-exceedance of this height for each dataset show the probability of pipes exceeding a range of vertical extents (Fig. 4b). Based upon these data the probability of a pipe extending vertically > 350 m is ~ 33% (Fig. 6ab)

### Stimulated hydraulic fractures

Our compilation of data from the USA shales (Fisher & Warpinski, 2011 – Fig. 3c) shows that generally the Marcellus is the shallowest reservoir, then the Niobrara, Barnett, Woodford and Eagleford. The maximum upward propagation of fractures initiated in these reservoirs is ~ 588 in the Barnett shale but in each case the vast majority of hydraulic fractures propagate much shorter distances (Fig. 5ab). The maximum upward propagation recorded to date in the Marcellus shale is ~ 536 m. The graphs show that the probability of an upward propagating fracture exceeding a height of 200 m, for example, is highest for those initiated in the Marcellus then the Barnett, Woodford, Niobrara and Eagleford shale reservoirs. Based upon these data the probability that an upward propagating hydraulic fracture extends vertically > 350 m is ~ 1% (Fig. 6ab), but the probability is probably lower than this because we cannot capture all of the shorter fractures. We cannot accurately estimate the average vertical extent for the same reason.



### Unintentionally stimulated hydraulic fractures

At the Tordis Field, offshore Norway, waste water produced due to oil production was injected at ~ 900 m below the surface. This caused hydraulic fractures to propagate approximately 900 m to the seabed. Pressure profiles from the injection well show a stepped fracturing of the overburden (Løseth *et al.* 2011). The injection lasted for approximately 5.5 months, while the leakage to seafloor may have occurred for between 16 and 77 days (Løseth *et al.* 2011).

## INTERPRETATION AND DISCUSSION

### Vertical extent

Offshore mid-Norway there are controls on the locations of the bases of the pipes as many emanate from overpressured strata and 66% terminate at the present-day seabed (Hustoft *et al.* 2010) and these controls cause the peak in the frequency versus depth plot between 300-350 m (Fig. 4a). Both of these factors have an influence on the shape of the probability of exceedance versus height curves (Fig. 4b). In contrast only 12 of the 360 pipes from offshore Mauritania terminate at a palaeo-seabed and a small number of pipes in the Namibe Basin do this. Despite the limitations of the datasets it is clear most of the natural hydraulic fractures reported here are 200-400 m in height and that very few natural fracture systems reported to date propagate beyond a height of 700 m. The tallest is 1106 m, which is comparable to the tallest injectites documented (Hurst *et al.* 2011). Lastly hydraulic fractures that cluster to form pipe structures generally propagate upwards further than stimulated hydraulic fractures (Fig. 6ab).

The vast majority of stimulated hydraulic fractures have a very limited vertical extent of < 100 m (Figs. 3c and 5a) and the tallest is ~ 588 m. These taller hydraulic fractures probably form by intersecting existing faults which has been recognised because the clustering and the magnitude of microseismic events changes (Warpinski & Mayerhofer, 2008).

### Controls on vertical extent

Stimulated hydraulic fractures probably form by a number of small fracture propagation events rather than a single one. The stimulation of the hydraulic fractures in shale gas reservoirs normally takes place over time periods of only 1-2 hours for a single fracturing stage. When this period has been increased, for example in the Barnett Shale, where pumping for an 11.7 hour period took place with a total volume of c. 5565 m<sup>3</sup>, the maximum height of hydraulic fractures was only ~ 266 m (Maxwell *et al.* 2002). During pumping periods of up to 11.3 hours into the Barnett Shale the relationship between height and pumping time and volume was shown not to be strong (Shelley *et al.* 2011) and fractures stopped propagating vertically after only 1-3 hours. Therefore there is little relationship between pumping time and fracture height when measured over these timescales. In the shale gas provinces local geology such as variations in lithology, provide natural barriers to propagation because of higher confining stress or high permeability which allows the fluid to bleed off (Fisher & Warpinski, 2011). For example in the Barnett shale the Viola and Ellenberger limestones located below the Barnett shale can limit the downward propagation of hydraulic fractures (King *et al.* 2008).

We propose that natural hydraulic fractures that cluster to form pipe structures have greater vertical extents for a number of reasons. There is much more fluid and much longer timescales available for multiple stages of fracture propagation. A volume of ~ 6 x 10<sup>9</sup> m<sup>3</sup> is reported for an aquifer in the North Sea (UK) (Heward *et al.* 2003). Although the flux of only some of the fluid from an aquifer would cause pressure to drop to hydrostatic levels and therefore only some of this fluid would have a role in pipe development, there are orders of magnitude higher volumes of fluid available than used in fracture stages in shale gas wells. Gas that comes out of solution during ascent of fluid in natural hydraulic fractures could also have a contributory role in propagation (Cartwright *et al.* 2007). The pipes recorded here are hosted within fine-grained, relatively homogenous successions on continental margins where there are fewer mechanical boundaries and generally low permeability strata that do not allow fluid to bleed off and therefore pressure to drop. Lastly there are significant geometrical differences between natural and stimulated hydraulic fractures and we do not know what influence this has on height. Despite these differences there are similar trends in the datasets. The vast majority of both natural and stimulated hydraulic fractures included in this study are < 500 m in vertical extent (Fig. 6a). This is again because of variations in-situ stress, weak

interfaces, material property contrasts and high permeability layers in sedimentary successions, particularly heterogeneous ones, provide natural barriers to fracture propagation.

At the Tordis field the average rate of injection of water was 7000 m<sup>3</sup> a day for 5.5 months (total volume ~ 1,115,000 m<sup>3</sup>). Fractures grew from ~ 900 m depth to the surface through Cenozoic (Tertiary) rather than Palaeozoic strata. But this volume of fluid is over ~ 123 times greater than typically used for fracture stages in the shale gas reservoirs and over a time period hundreds of times longer.

Løseth et al, (2011) reported that pressure profiles from the injection well show a stepwise fracturing of the overburden and that fractures actually propagated for 900 m reaching the surface (the seabed). The complexity of fracture propagation, role of bed boundaries and pre-existing natural fractures was also demonstrated at centimetre to metre scale through the mine-back experiments carried out in the USA where stimulated fractures were exposed by excavating them (e.g. Cipolla *et al.* 2008). Propagation continues once the stress at the new boundary exceeds the least principal stress and the tensile strength of the host sediment and the stress-intensity at the fracture tip is lower than the critical stress-intensity of the rock being fractured. Therefore to develop the vertically most extensive fracture systems there needs to be long, probably multiple episodes of injection of high pressure fluid (probably >> 1 day). There would be several steps in the propagation of the fracture system, breaking through permeable beds and mechanical boundaries. Mechanically homogeneous successions with low permeability will result in vertically more extensive fractures than heterogeneous formations with variable permeability and confining stress.

### **Implications and further work**

Further research should include additional datasets, particularly from new settings that have not undergone fracturing treatments to further increase confidence that exceptional propagation heights have been captured. Additional data may allow for a better understanding of several potential relationships between the height of fractures and variables such as the type of stress regime (i.e. conducive for shear failure or tensile failure), rock type, volume of pumped fluid and pumping time.

There are some geological scenarios where there could be connectivity of permeable reservoirs through a significant thickness of overburden. For example sand injectites can cut through ~ 1000 m of shale (e.g. Hurst *et al.* 2011) and this could, given long enough pumping time cause critical pressurisation of shallower strata and therefore shallower fractures. These and other geological scenarios should be considered and modelled.

Lastly, stimulated hydraulic fractures have been proposed as a mechanism for methane contamination of aquifers located 1-2 km above the level of the fracture initiation in the Marcellus shale (Osborn *et al.* 2011). Because the maximum upward propagation recorded to date in the Marcellus shale is ~ 536 m this link is extremely unlikely (Davies, 2011; Saba & Orzechowsk 2011; Schon, 2011). Other mechanisms for contamination such as the leakage of biogenic or thermogenic gas from porous and permeable strata behind well casing and natural migration of methane are more likely.

## CONCLUSIONS

Natural hydraulic fracture pipes have the potential to propagate upwards further than stimulated ones. The maximum upward propagation recorded for a stimulated hydraulic fracture to date is ~ 588 m in the Barnett shale in the USA. Based upon the data presented here the probability that a stimulated hydraulic fracture extends vertically beyond 350 m is ~1%. Very few natural hydraulic fractures pipes or simulated hydraulic fractures propagate past 500 m because layered sedimentary rocks provide natural barriers to growth.

Microseismic measurement of fracture propagation is an essential monitoring tool which allows us to provide an evidence base for the setting of the minimum vertical separation between the shale gas reservoir and shallower aquifers. This is a comprehensive compilation of data, but of course should be added to with new fracture height data from other regions, as the different geological conditions may result in unusually short or tall fractures. Building upon this dataset and deriving probabilities from it will help inform industry and academic geoscientists and engineers, regulators, non government organisations and publics on safe separation distances and help ensure environmentally safe shale gas operations.

## ACKNOWLEDGEMENTS

We are very grateful to Steve Wolhart (Halliburton) for providing the unpublished data from the Niobrara shale (Fig. 3). Katie Roberts is thanked for providing field photographs (Fig. 1ab), Jonny Imber, Roger Crouch, Jon Trevelyan and Joe Cartwright are for discussion, although the opinions are those of the authors. Both Mads Huuse (Manchester University, UK) and Terry Engelder (The Pennsylvania State University, USA), provided very thorough, constructive and informative reviews that allowed important revisions to the manuscript.

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## FIGURES

Figure 1 (a) Examples of natural hydraulic fractures in shale (b) close-up of a natural hydraulic fracture filled with shale clasts (both examples from onshore Azerbaijan).

Figure 2 Schematic diagram showing stimulated hydraulic fractures within a shale gas reservoir, natural hydraulic fractures initiated at a naturally overpressured reservoir, the vertical extent of hydraulic fractures reported here and the safe separation between shale gas reservoir and shallower aquifer. VE – vertical extent.

Figure 3 (a) Map of the globe showing location of the eight datasets. Red font – datasets for stimulated hydraulic fractures, blue font – datasets for natural hydraulic fractures (pipes). (b) Seismic line from offshore Mauritania showing a representative vertical pipe imaged on 3D seismic reflection data and its vertical extent. (c) Graph of stimulated hydraulic fractures in the Marcellus, Barnett, Woodford and Eagleford shales (after Fisher & Warpinski, 2011) and including unpublished data provided by Halliburton for the Niobrara shale. Inset – extract of the graph showing how the vertical extents of fractures were measured. All depths are in true vertical depth (TVD). The black dashed line - depth of the stimulation of the hydraulic fractures. Coloured spikes – separate hydraulic fractures propagating upwards and downwards from the depth of stimulation.

Figure 4 Graph of frequency against vertical extent for natural hydraulic fractures (pipes) identified on 3D seismic data from (a) offshore Mauritania, (b) Namibe Basin (c) mid Norway.

Figure 5 Graphs of frequency against hydraulic fracture height for (a) upward and (b) downward propagating fractures in the Marcellus, Barnett, Woodford, Eagleford and Niobrara shales. Graphs of probability of exceedance against height of (c) upward propagating fractures and (d) downward propagating fractures.

Figure 6 (a) Graph of frequency against fracture height for all stimulated and natural hydraulic fractures. (b) Graph of probability of non-exceedance against fracture height for stimulated and natural hydraulic fractures.

- Maximum reported height of an upward propagating hydraulic fracture is ~ 588 m.
- Maximum height for a natural hydraulic fracture networks is ~ 1106 m.
- The probability of a stimulated and natural hydraulic fracture extending vertically > 500 m is ~ 1% and ~ 15% respectively.















